DRAFT for Comment: 9/12/05

Please Note: Portions of this draft have not been reviewed by some members of the IVSG Steering Committee, and it does not necessarily represent the adopted policies of all member organizations.

Development Plan for the Phased Expansion of Transmission to Access Renewable Resources in the Imperial Valley

Report
of the
Imperial Valley Study Group

Presented to the California Energy Commission

2005 Integrated Energy Policy Report

September 30, 2005

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NOTE: Appendices are not included with the 9/12/05 Draft for Comment

Appendices

GLOSSARY

ACE	Area Control Error
AGL	Above Ground Level
APS	Arizona Public Service Company
CA ISO	California Independent System Operator
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFE	Comisión Federal de Electricidad
CEERT	Center for Energy Efficiency and Renewable Technologies
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
Definitive Plan	Transmission facilities specified in sufficient detail to be approved by regulatory agencies for ratemaking and construction
EIR	Environmental Impact Report
FERC	Federal Energy Regulatory Commission
FS	Facilities Study
Gen-tie	Transmission line connecting a generator to the grid
IID	Imperial Irrigation District
IOU	Investor Owned Utility
IVSG	Imperial Valley Study Group
KGRA	Known Geothermal Resource Area
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
MW	Megawatt (1,000 kW)
MWD	Metropolitan Water District
NERC	North American Electricity Reliability Council
SP 15	South of Path 15
PEA	Proponent’s Environmental Assessment
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PWG	IVSG Permitting Work Group
RAS	Remedial Action Scheme
RMR	Reliability Must Run
ROW	Right Of Way
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
Sec 399.25	Section of California Public Utilities Code
SIS	System Impact Study
SPS	Special Protection System
SRP	Salt River Project
STEP	Southwest Transmission Expansion Plan
TCSG	Tehachapi Collaborative Study Group
TO	Transmission Owner
TWG	IVSG Technical Work Group
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

Executive Summary

California's Imperial Valley contains more than 2,200 MW of proven geothermal power reserves and one-quarter of the state's entire solar generation potential. This is in addition to the more than 500 MW of renewable resources that the Imperial Irrigation District (IID) delivers across its system today. Meeting the state's renewable energy goals requires access to these new resources. But there is very little transmission capacity available to export such additional generation.

The Imperial Valley Study Group (IVSG) was formed to recommend a phased plan for the development of the transmission necessary to export 2,200 MW of renewable generation from the region. As with the Tehachapi Collaborative Study Group, the development of transmission solutions to access renewable resources has been sought by the California Public Utilities Commission (CPUC) and by the California Energy Commission (CEC) in its 2005 Integrated Energy Policy Report proceeding.

The IVSG is a voluntary planning collaborative made up of regional stakeholders. Participants include all regional Transmission Owners, the California Independent System Operator (CAISO), CPUC, CEC, generation developers, local, state and federal agencies, environmental and consumer groups and other interested parties. Its work has been led by the Imperial Irrigation District (IID), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE), and is fully supported by Los Angeles Department of Water and Power (LADWP). Its mission is to evaluate and recommend regional transmission solutions that meet threshold requirements for reliability, least cost development and for minimizing environmental impact. These solutions cross control area boundaries and require coordination among several transmission owners, Load Serving Entities, regulatory and government agencies and other interests.

Given this fundamental need for regional cooperation, the IVSG does not promote the interests of any one organization. It identified alternative solutions for study based on its own independent evaluation of the existing transmission infrastructure. IVSG planning work does, however, build on IID's proposed Green Path Initiative. As explained at CEC workshops in 2004 and 2005, this is an on-going program to upgrade the IID transmission system to support the export of additional renewable generation from the Imperial Valley to multiple delivery points. IVSG planning has also taken advantage of SDG&E's study of a new 500 kV connection to San Diego. SDG&E's work has provided considerable data for evaluating incremental power export from the Imperial Valley. SDG&E has also, through the STEP planning process, involved transmission planners from the entire southwest region in evaluating new high voltage connections between the IID and CAISO systems. This has helped to bring the IVSG's own studies of power flows from the Imperial Valley to the attention of planners who are not directly involved in the IVSG.

IID and LADWP operate their own control areas, distinct from the CAISO; both are independent of regulation by the CPUC and FERC. The IVSG development plan respects their regulatory independence, while also establishing a basis for the cooperation necessary to support such a large-scale development involving publicly owned and investor-owned utilities operating across multiple control areas.[1]

The recommendations in this report flow from detailed transmission planning studies conducted by the participants. The IVSG first identified a range of transmission alternatives capable of exporting 2,200 MW of new generation from the Imperial Valley area to regional load serving entities. Initial power flow screening analysis led the group to select three of these alternatives for additional, extensive study. Power flow, voltage stability and post-transient studies considered single and double contingencies at key facilities in the region. Production simulations were performed to estimate the savings in production cost and the impact on congestion on major lines with 2,200 MW of new generation added. To determine the optimal way of phasing this development, the IVSG re-studied the upgrades required for delivering the new generation in smaller increments. This report includes a full description of the study assumptions, methodology and results. In addition to export paths, SCE and SDG&E evaluated network upgrades on their systems necessary to make Imperial Valley generation deliverable to load centers.

Independent of the IVSG, LADWP has also conducted transmission planning activities to develop a transmission plan to access Imperial Valley geothermal resources to serve LADWP customers. This IVSG report takes note of LADWP's transmission development plan.

The transmission solutions presented in this report are conceptual and do not constitute a detailed plan of service. The IVSG had neither the time nor the resources necessary to complete the kind of analysis typically required for System Impact Studies or Facilities Studies. Additional studies will therefore be required before any of the proposed facilities could be approved for interconnection by the transmission owner, or by regulatory agencies (in the case of the Investor Owned Utilities) for ratemaking and construction, or for increasing path ratings. This report explains the limitations of the studies on which its development recommendations are based, and identifies the further studies needed.

Phasing of Transmission Development

The IVSG transmission plan consists of three development phases, designed to provide market access for 2,200 MW of renewable resources, primarily geothermal and solar, in the Imperial Valley region. These resources are identified in the CEC Renewable Resources

[1] Arizona Public Service (APS), the Western Area Power Administration (WAPA) and the Comisión Federal de Electricidad (CFE) also operate separate control areas in the region; all have participated in the iVSG.

Development Report[2]. After IVSG transmission planning work had been completed, SDG&E announced a major purchase of solar power from the Imperial Valley. No wind power projects have yet been proposed to IID or the Imperial County Planning Department. In IVSG studies, the electrical characteristics of the new generation were modeled as geothermal units. This notwithstanding, the IVSG plan readily supports interconnection of any renewable generating technology to the IID system.

Phase 1 would accommodate three new geothermal plants (or equivalent resources), 645 MW total, capable of being in service by the end of 2010. The size and timing of Phase 1 is based on CalEnergy's estimate of its work to conclude Power Purchase Agreements for three such plants. These generating units at the southern end of the Salton Sea would connect to the existing IID system at IID's Midway substation, which would be expanded to accommodate connections to the additional generating plants. Upgrades of the IID transmission system would be required from its Highline substation to El Centro substation (approximately 20 miles), and from El Centro to the Imperial Valley substation (approximately 18 miles), where the power would be delivered to the CAISO grid. These IID upgrades would provide 1,000 MW of additional transfer capacity across this path, more capacity than necessary to accommodate the initial 645 MW of new renewable generation. These upgrades would take advantage of existing facilities to minimize cost and environmental impact; they would be constructed, owned and operated by IID.

The other major component of Phase 1 is a new 500 kV line from the Imperial Valley (IV) substation to San Diego County, with 230kV connections to SDG&E's load center. SDG&E's project to accomplish this is called the Sunrise Powerlink. SDGE has proposed building and owning this line and is in the process of planning this project, which was studied as part of the IVSG effort. Alternatively, portions of that line or another 500 kV line in Imperial County could be built and owned by IID. IVSG studies established that a line from the IV substation to San Diego County would make Imperial Valley generation deliverable to load centers in San Diego and to other load centers in Southern California and to the north.

Phase 2 would accommodate an additional three geothermal plants (or equivalent), or 645 MW of incremental generation, bringing the cumulative new export capacity total to 1,290 MW. Based on CalEnergy's development schedule, Phase 2 upgrades should be timed to be available by approximately the end of 2016. These upgrades would also provide market access for Concentrating Solar Power (CSP) generation projects, and/or other renewable generation projects developed in that timeframe, in place of or in addition to new geothermal units. Phase 2 would upgrade IID's existing El Centro-Avenue 58 transmission line, from its El Centro substation to its planned Bannister substation west of the Salton Sea geothermal field. The El Centro-Bannister upgrade to 230 kV, approximately 25 miles, would utilize existing ROW. IID would also construct a new 230 kV line from the Bannister substation to a new San Felipe 500/230 kV substation to interconnect to the proposed Sunrise Powerlink . This San Felipe substation could potentially provide an additional interconnection between

[2] The CEC Renewable Resources Development Report (RRDR) was adopted by the CEC and sent to the Legislature on November 19, 2003. SB 1038 required the CEC to prepare this plan for the development of California's renewable resources.

the IID and CAISO systems, and thus another point for the delivery of renewable resources to Southern California loads. IID would construct, own and operate these upgrades.

Phase 3 upgrades would make an additional 910 MW of Imperial Valley generation deliverable to the CAISO grid, bringing cumulative incremental export capacity to 2,200 MW. As with Phases 1 and 2, most of the new Imperial Valley generation would be scheduled to SDG&E, to minimize congestion at Devers. Additional upgrades of the IID transmission system would support delivery of renewable resources to the Mirage/Devers 230 kV system, and/or accommodate unintended flow across Path 42. . These additional upgrades of the IID system in Path 42 take advantage of existing facilities and ROW to minimize cost and environmental impact. Upgrades of the SCE portion of Path 42, from Mirage to Devers, may also be required.

In practice, the size and timing of the phases will be determined by where the renewable power is sold via power purchase agreements (PPAs). Phases 1-3 anticipate power sales primarily to customers able to take delivery from the CAISO system, for example at the Imperial Valley or proposed San Felipe substations. Several Load Serving Entities who would not take delivery from CAISO interconnections have expressed interest in obtaining Imperial Valley geothermal power. Power sales to LADWP, and/or to entities in Arizona could require construction of the proposed Indian Hills substation, and/or upgrades of IID's connections to the WAPA and/or APS systems. It is also possible that power sales could require the identified Phase 1-2 upgrades (for deliveries to the CAISO grid) and upgrades of other IID interconnections.

LADWP and IID have recently announced that they are exploring a 500 kV tie between their systems, at the proposed Indian Hills 500/230 kV substation, as described more fully below. The IVSG did not study such a connection, and so could not include it in the development phases defined in this report. Construction of such a line could alter the size, timing and transmission upgrades proposed for each development phase. Study of the effect of this DWP-IID connection on Imperial Valley development is anticipated to begin in fall 2005.

The major components of each phase include:

Phase 1 Export capacity: 645 MW In Service Year: 2010 Estimated cost = $	
Lines:	Upgrade Highline to El Centro and to IV substations, approx. 40 miles New Geo Collector substation 1 to Midway, approx. 15 miles New IV to San Diego-Central, approx. 90 miles, 500 kV; with 230 kV lines into SDG&E load center
Substations:	New Geo Collector substation 1, 230 kV Expand El Centro substation; expand Midway substation

Phase 2 Export capacity: 645 MW (1,290 MW cumulative) In Service Year: 2016 Estimated cost = $	
Lines:	New Bannister to San Felipe substation, 20 miles, 230 kV Upgrade existing El Centro to Bannister, approx. 25 miles New IID Collector substation 2 to Bannister, 230 kV
Substations:	New IID Collector substation 2, 230 kV New IID San Felipe 500/230 kV substation

Phase 3 Export capacity: 910 MW (2,200 MW cumulative) In Service Year: 2020 Estimated cost = $	
Lines:	Upgrade existing Coachella Valley to Mirage/Devers, 40 miles Upgrade existing Bannister to Coachella Valley, 55 miles Tie Bannister to Collector substations to Midway, 1 mile New Coachella to Indian Hills, approx. 5 miles
Substations:	Expand Coachella Valley substation

LADWP Transmission Development

The LADWP transmission plan consists of the development of a new 500 kV transmission line from IID to LADWP associated with the development of 400 MW renewable resources, primarily geothermal, in the Imperial Valley region. The IID-LADWP transmission line is planned to be connected to a new IID Indian Hills substation and a new LADWP Upland substation. The Indian Hills substation is envisioned to interconnect the planned Palo Verde – Devers Transmission Line 2. The proposed Upland substation will be constructed along the existing 287 kV Victorville – Century transmission line. The transmission plan also includes upgrading a section of the Victorville – Century line from 287 kV to 500 kV, and 230 kV line upgrades within the IID system.

The IID-LADWP transmission line will also be used to deliver about 400 MW of LADWP's Palo Verde power which is currently delivered on the existing Palo Verde-Devers Transmission Line 1.

The major components of the LADWP transmission plan include:

LADWP Transmission Plan	
Estimated renewable export capacity: 400+ MW	
Estimated cost = $	
Lines:	New Indian Hills to Upland, 500 kV, 100 miles
	Upgrade existing Upland to Victorville to 500 kV, 34 miles
	Upgrade existing Bannister to Coachella Valley, 55 miles
	Tie Bannister to Collector substations to Midway, 1 mile
	New Coachella to Indian Hills, approx. 5 miles
Substations:	New Indian Hills 500/230 kV substation
	New Upland 500 kV substation

Permitting and Approval

The IVSG attempted to consider the 2,000+MW development as one large project, divided into phases extending across several years. This approach was intended to identify opportunities for consolidating all necessary approvals, in order to support development on a schedule responsive to California's Energy Action Plan goals for the addition of both renewable generation and new transmission capacity. The report presents several recommendations to this end.

At the time of this writing, however, the routing of the Sunrise Powerlink has not been finalized, and the environmental study requirements of this major component thus cannot be known. As a result, the permitting plan is divided into sections addressing IID upgrades, SCE upgrades, SDG&E upgrades and LADWP upgrades, with strategies for expediting the required permitting outlined in each. The report also looks forward to a comprehensive plan for consolidating the permitting of all components of the multi-phase project, and for streamlining the study and approval processes necessary.

The IVSG Permitting Work Group (PWG) has informed local, state and federal organizations and agencies that will be involved in any aspect of review and approval of the development, or could be affected by it, of the potential build-out. The agencies have requested that the review and approval process be consolidated across the multi-phase project to avoid unnecessary re-study and to make the most efficient use of agency staff time dedicated to the overall project.

The IVSG recommends that permitting work for the overall development be organized as follows:

- Structure a broad, Programmatic EIR (P-EIR) encompassing the overall, multi-phase project. A programmatic approach provides the best vehicle to address all of the environmental concerns from the different phases. The P-EIR would take its project description from the development plan drafted by the IVSG.

- Develop a Memorandum of Understanding among IID, SDG&E, LADWP and CalEnergy, to share the costs for the Programmatic EIR and the work of writing the descriptions of each entity's development plans. IID would be the lead agency on this EIR; the CPUC and CEC will be invited to participate from the beginning.

- IID, SDG&E, LADWP and SCE will work to identify the location of necessary transmission corridors being proposed for their individual phase components so that the Programmatic EIR can reflect all necessary plans. The actual NEPA documents to amend the California Desert Conservation Area Plan will have to be developed in conjunction with the EIRs or EAs for the second tier of Imperial Valley generation/transmission development

The IVSG has developed this conceptual plan with the advice and cooperation of regulatory and agency staff.[3] The MOU parties will seek to continue this cooperation as they undertake the required environmental studies. The IVSG can also work to bring the overall project to all state and federal regulators at the same time. State and federal agency staffs have heavy workloads. One method of assisting them, which could also speed up the review process, would be to bring in their consultants earlier in the review process. Currently, consultants cannot be hired before the CPUC first directs jurisdictional utilities to file a CPCN application. This adds considerable time to its review and approval process. Additional recommendations for streamlining and expediting the review and approval process are included in Chapters 4 and 6.

[3] The IVSG Permitting Work Group appreciates the cooperation and involvement of the BLM, CPUC, Imperial County Planning Department, Imperial County Air Pollution Control District, and the California Department of Parks & Recreation.

1.0 Background and Purpose of the Imperial Valley Study Group

1.1 State Renewable Energy Goals And Imperial Valley Resources

California law requires investor-owned utilities, starting in 2003, to increase procurement of power from renewable resources by 1% per year until it comprises 20% of their supply mix, by no later than the end of 2017.[4] California's publicly owned utilities, although not bound legally by this requirement, have adopted resolutions committing them to achieve this 20% target as well. The California Energy Commission estimates that meeting the SB 1078 20% goal will require 30,160 GWh/year of additional renewables generation in 2017.[5] Imperial Valley geothermal generation is estimated to make up 55% (16,888 GWh) of this amount. Imperial County is also estimated to have one-quarter of the state's entire solar generation potential, as well as small amounts of wind and biomass resources. Figure 1-1 below shows the location of Known Geothermal Resource Areas (KGRAs) in Imperial County.

In 2003, the Energy Commission, the CPUC and the Consumer Power and Conservation Financing Authority jointly adopted, and the Governor subsequently endorsed, a state Energy Action Plan. This plan accelerates achievement of the 20% procurement goal to 2010. To reach this goal, a total of about 6,600MW of renewables generation is needed. The CEC identified Imperial Valley geothermal power as a potential source of approximately one-third, 2,142 MW, of this requirement.

Achieving these goals requires new and upgraded transmission infrastructure capable of delivering power from major renewable resource areas, including the Imperial Valley and the Tehachapi region, to the load centers. In June 2004, CPUC Decision 04-06-010, "Interim Opinion on the Transmission Needs in the Tehachapi Wind Resource Area,"[6] convened a collaborative study group to develop a comprehensive development plan for the phased expansion of transmission capabilities in the Tehachapi area. The study group was to be coordinated by the CPUC with assistance from the CAISO, and with the participation of the IOUs, wind power developers and other stakeholders. The Tehachapi Collaborative Study Group (TCSG) filed its report with the CPUC as required on March 16, 2005. This report presents a preliminary recommendation for the phased development of transmission facilities to access Tehachapi wind resources.

This CPUC decision also required the TCSG to consider whether to form additional planning collaboratives to develop transmission solutions for other renewable resource areas of the state. In response, the TCSG established a committee and directed it to explore the formation of a study group to develop a phased development plan capable of accessing new Imperial Valley geothermal resources. At the same time, the CEC Integrated Energy Policy Report proceeding calls for the development of transmission solutions capable of accessing renewable resources, including Imperial Valley geothermal resources. The Imperial Valley

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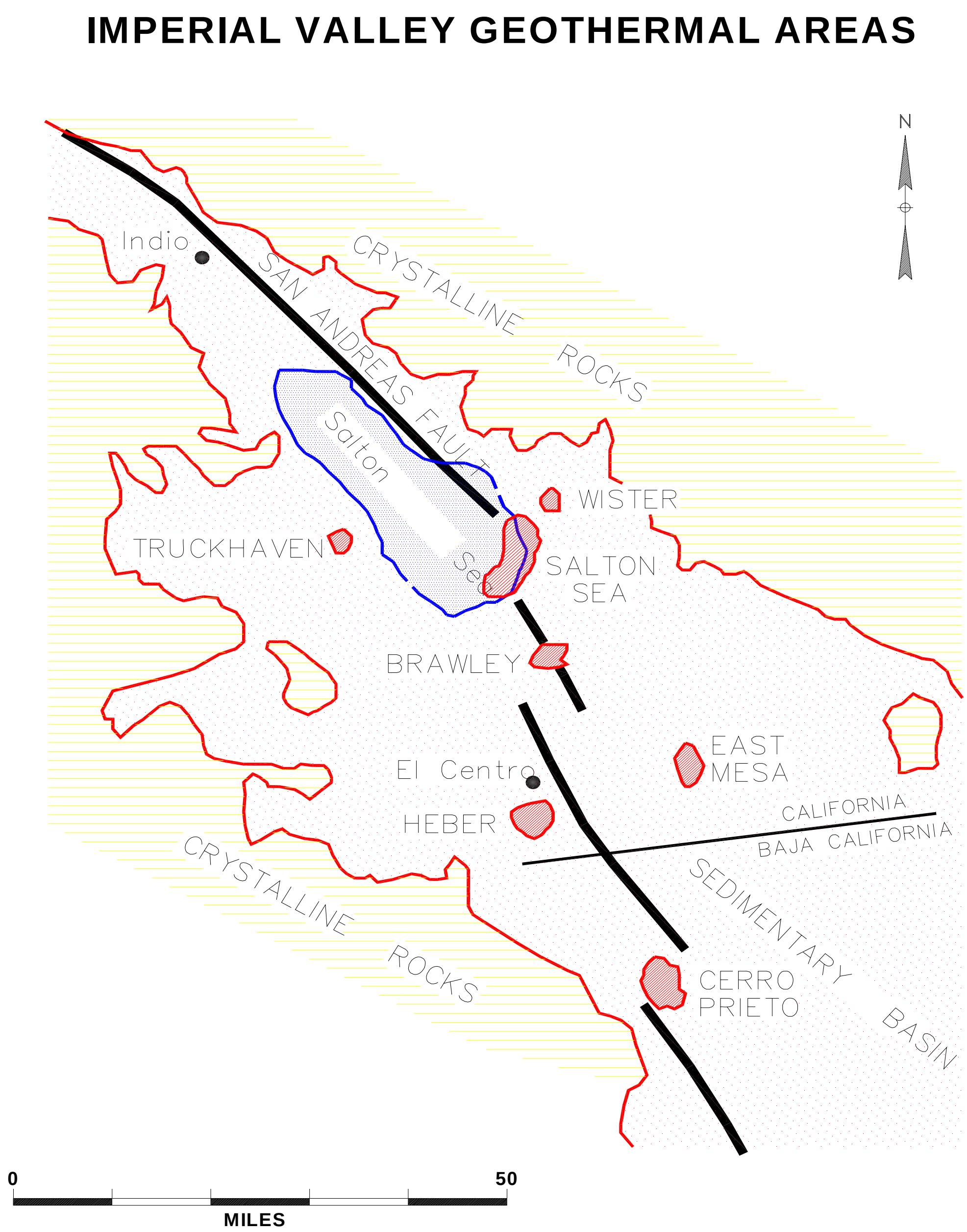
[4] Senate Bill 1078, Sher, Chapter 516, Statutes of 2002; and SB 1038, Sher, Chapter 515, Statutes of 2002.
[5] CEC, Renewable Resources Development Report, p. 139.
[6] D.04-06-010 was issued in CPUC proceeding I.00-11-001. Phase 6 of this proceeding focuses on transmission constraints affecting development of renewable resources in the state.

Figure 1-1


IMPERIAL VALLEY GEOTHERMAL AREAS
N
Indio
CRYSTALLINE ROCKS
SAN ANDREAS FAULT
Salton Sea
WISTER
TRUCKHAVEN
SALTON SEA
BRAWLEY
El Centro
EAST MESA
HEBER
CALIFORNIA
BAJA CALIFORNIA
CRYSTALLINE ROCKS
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Study Group (IVSG) was formed in response to these policy directives, with the goal of supporting achievement of the renewable energy goals of the Energy Action Plan and state law.

1.2 Mission of the Study Group

At its first meeting in November 2004, IVSG participants established a goal of specifying a phased development plan for the construction of transmission upgrades capable of exporting 2,200 MW of geothermal power from the Imperial Valley. In view of the very large solar generation potential in Imperial County, the IVSG subsequently decided to address the export of power generated by any renewable resource technology rather than focusing exclusively on geothermal power. In Phase 1 of the IVSG plan (the period to 2010), however, geothermal power is likely to be the predominant resource developed, and the transmission planning studies were completed using the electrical characteristics of geothermal generating units.

IVSG participants also set a goal of having its development plan represent the consensus recommendation of the stakeholder group to the extent possible. A joint planning process was intended to bring the knowledge and interests of key stakeholders together into an upgrade plan capable of providing the greatest statewide benefit at the least cost. The group recognized the support of key stakeholders for this plan to be essential if the recommended upgrades are to survive the challenges to final siting approval. Laying a foundation for approval and construction of physical transmission upgrades was seen as an essential part of the work of the study group.

1.3 Study Group Process and Participants

At its first meeting the Study Group adopted ground rules for cooperative group interaction. These were intended to make its work and decision-making as transparent as possible. Minutes of each meeting, reviewed and adopted by participants, have established a written record of the group's (and each committee's) progress. Meeting agendas, minutes and presentation materials are available on the IVSG website, www.energy.ca.gov/ivsg. Minutes of the IVSG Technical Work Group discuss study assumptions and the results of the technical transmission planning studies performed. This on-going study work has been reviewed at each meeting of the full Study Group. Overall, the study group has pursued its technical work in ways that help build stakeholder support for its recommended development plan. Participants recognize collaboration as essential to the development of this broad support.

The plenary Study Group established three committees to pursue its planning work:

- A Steering Committee, to direct the overall effort. The Steering Committee has lead responsibility for compiling the group's work into a recommended development plan. Members include IID, SDG&E, SCE, the CPUC, CAISO, CalEnergy, and CEC/CEERT.

- A Technical Work Group (TWG) performs detailed transmission planning studies. TWG members include, among others, all the Transmission Owners in the region: IID, SDG&E, SCE, CFE, WAPA, Arizona Public Service (APS), Metropolitan Water District (MWD); and the CAISO, CPUC, CEC/CEERT.

- The Permitting Work Group has the responsibility for identifying all required permits, and for designing a plan for consolidating and expediting the permitting of the entire 2,200 MW generation-transmission development. The PWG has worked to inform many local, state and federal agencies and organizations that may be involved in or affected by the development. PWG members include: Border Power Plant Working Group, CalEnergy, California Dept. of Parks and Recreation, Environmental Planning Group, IID, Imperial County Planning Dept., Imperial County Air Pollution Control District, Los Angeles Dept. of Water and Power, SDG&E, Sempra, Sierra Club, SCE, and US Bureau of Land Management.

After discussion, the IVSG adopted an initial study plan proposed by IID, CalEnergy, CEERT and SDG&E at its first meeting. The IVSG subsequently approved amendments to this plan, as it evolved to incorporate the results of completed studies. IVSG transmission study assumptions, methodologies and results are outlined in [Chapter 3]. As discussed there, power flow and other transmission planning studies have been performed by the major transmission owners and the CAISO. As agreed, each participant has paid its own costs.

IVSG ground rules commit study group participants to work in good faith toward consensus support for a recommended development plan. The ground rules also specify that if it proves impossible to arrive at a consensus recommendation, participants disagreeing with the majority plan are encouraged to submit their written critique of that plan, and/or to submit an alternative development plan. [The Border Power Plant Working Group and the Sierra Club have prepared such an alternative plan, and the IVSG calls the attention of the CEC, CPUC and the Governor to that plan.]

A draft of this report was written by the Steering Committee and sent to the entire IVSG distribution list and the STEP (Southwest Transmission Expansion Plan) distribution list with a request for comment. The comments were then reviewed by the Steering Committee and incorporated into the report as deemed appropriate.

The plenary Study Group met five times between November 2004 and the submittal of this report on September 30, 2005. The Technical Work Group meet bi-weekly during this period to accommodate the substantial workload of transmission planning studies required. The Permitting Work Group met six times, beginning in April 2005 to involve county, state and federal agencies in designing a plan for consolidating and expediting permitting and approvals. The following organizations have participated in study group meetings:

Arizona Public Service Company
Aspen Environmental Group
R.W. Beck

Border Power Plant Working Group
CalEnergy/MidAmerican Energy Company
California Department of Parks and Recreation
California Energy Resources Conservation and Development Commission
California Independent System Operator
California Public Utilities Commission
Center for Energy Efficiency and Renewable Technologies
City of San Diego
Colorado River Transmission Committee
Comisión Federal de Electricidad
Coral Power LLC/Shell Gas & Trading
Davis Power Consultants
Debenham Energy LLC
Desert Southwest Transmission
Environmental Planning Group
Imperial County Air Pollution Control District
Imperial County Planning Department
Imperial Irrigation District
K.R. Saline & Associates
Kritikson & Associates
Lake Elsinore Advanced Pumped Storage
Lewis Brisbois Bisgaarad & Smith LLP
Los Angeles Department of Water & Power
Metropolitan Water District
Ormat Technologies, Inc.
PPM Energy
Salt River Project
San Diego Gas & Electric Company
San Diego Renewable Energy Office
Sandia National Laboratory
Sempra Energy
Sierra Club
Solargenix
Southern California Edison Company
Stirling Energy Systems, Inc.
Theroux Environmental
US Bureau of Land Management
US Bureau of Reclamation
Western Area Power Administration

2.0 Recommended Development Plan

This chapter outlines the development plan recommended by the IVSG, its impact on regional flows and existing and planned facilities, and discusses the considerations that led to the compilation of the plan. This plan may be modified in the future, to accommodate a recently-proposed interconnection of the IID and LADWP systems. The IVSG, however, did not study the 500 kV line now proposed by LADWP, and so had no basis for integrating that line into the development phases recommended here.

The plan has two major elements: upgrades of the existing IID system; and construction of a new 500 kV line from the Imperial Valley (IV) substation to San Diego County, with 230kV connections to SDG&E's load center. SDG&E's project to accomplish this is called the Sunrise Powerlink. SDG&E has proposed building and owning this line and is in the process of planning this project, which was studied as part of the IVSG effort. Alternatively, portions of that line or another 500 kV line in Imperial County could be built and owned by IID. IVSG studies established that a line from the IV substation to San Diego County would make Imperial Valley generation deliverable to load centers in San Diego and to other load centers in Southern California and to the north.

The plan is divided into three phases, corresponding roughly to an anticipated schedule for selling the power from Imperial Valley renewable resources. The detailed studies performed to identify plan components and qualify the electrical performance of the plan are described in Chapter 3.

2.1 Development Phases

The IVSG recommends that the overall Imperial Valley generation-transmission development project be approached in these three phases:

	Year	New Generation	Cumulative	Power Flow
Phase 1	2010	645 MW	645 MW	IID to IV sub to new San Diego-Central, 500 kV
Phase 2	2016	645 MW	1,290 MW	IID to new San Felipe sub to San Diego-Central
Phase 3	2020	910 MW	2,200 MW	Increased flows on Phase 1-2 paths, plus upgrade Path 42

The detailed components of the upgrades required for each phase are described in section 2.2. A schematic depiction of these proposed upgrades is included below in Figure 2.1.

This recommended plan seeks both to maximize the use of the proposed IV-San Diego 500 kV line for renewables, and to avoid adding to the very large volume of power flows forecasted for delivery to SCE's Devers substation. The Palo Verde-Devers #2 (planned in-service 2009) is expected to bring large amounts of existing gas-fired generation from Arizona and new gas-fired generation from the Blythe area to an already-congested hub at Devers; a substantial amount of new thermal generation is also planned to be built adjacent to Devers. Plans to upgrade the SCE system west of Devers are costly and complex. In the timeframe of the IVSG development plan, it was not possible to adequately study the network upgrades necessary to make Imperial Valley generation deliverable west of Devers. The IVSG plan does, however, take account of the unintended flows likely across Path 42 from the Imperial Valley to Devers even when all Imperial Valley generation is scheduled to the CA ISO across the proposed SDG&E 500 kV line into San Diego county.

In Phases 1 and 2, geothermal power is the most likely renewable resource to be developed. The size and timing of these phases is based on the development and construction of three 215 MW geothermal power plants proposed to be built by CalEnergy at the Salton Sea KGRA. Plant construction requires 26 months. CalEnergy estimates that, subject to securing Power Purchase Agreements for each plant's output and financing, it can have three plants (645 MW) in service by the end of 2010; and that it could have an additional three plants of the same size in service every other year (2012, 2014, 2016).

The total transfer capacity to be built in each phase is considerably greater than the amount indicated here, for several reasons. SDG&E requires the new 500 kV line to maintain reliable operation of its system, as well as to access renewable resources and lower cost power. The 500 kV line required for Phase 1 provides enough capacity for all three phases of the IVSG development, even though Phases 2 and 3 are likely to be built several years after the 500 kV line goes into service. The upgrades of the IID system will add 1,000 MW of total transfer capacity to the present rating of those paths, more than is needed to export the 645 MW of renewable power in both Phases 1 and 2. It minimizes environmental impact and is more cost-effective to build facilities sufficient for several years' needs, rather than building in smaller increments. Transfer capacity not used by new geothermal projects in Phases 1 and 2 will be available to export other solar and/or other power from the Imperial Valley.

In practice, the size and timing of the phases will be determined by where the renewable power is sold. Phases 1-3 support power sales to customers able to take delivery from the CAISO system, for example at the Imperial Valley substation. The proposed tie between the LADWP and IID systems could require upgrade of IID's Coachella system sooner than anticipated in the IVSG plan. Power sales to purchasers in Arizona could also defer the need for the Phase 1 or Phase 2 upgrades of the IID system, and instead might require upgrades of IID's connections to the WAPA and/or APS systems (at the Buck/Blvd. Substation in Riverside County), and/or to APS, at the Pilot Knob substation. Flows across these upgrades to purchasers to the east of IID would offset flows from Arizona into California, potentially reducing congestion on key east-west paths. It is also possible that power sales could require the identified Phase 1-2 upgrades (for deliveries to the CAISO grid) and upgrades of other IID interconnections.

Figure 2.1 Diagram of Phase 1 Upgrades (IID to provide)

Diagram of Phase 2 Upgrades

Diagram of Phase 3 Upgrades

2.2 Major Components of Each Phase and Conceptual Cost Estimates

Phase 1 description (IID to provide)

Phase 2 description

Phase 3 description

Path 42 Upgrades

Path 42 is a 230 kV transmission path between Southern California Edison (SCE) and the Imperial Irrigation District (IID). The path has a WECC rating of 600 MW and includes the Coachella-Ramon-Mirage 230 kV and Coachella-Devers 230 kV lines.

The trigger for Path 42 upgrades would be based on a developer's request to secure a Power Purchase Agreement with SCE for the amount of power greater than the 600 MW rating. The upgrade would be based on the best technical and economic solution and would depend on the amount of resource delivery to the CAISO grid.

The possible first stage of upgrades would include reconductoring the Coachella-Ramon-Mirage 230 kV and Coachella-Devers 230 kV lines to a higher-rated conductor. WECC Rating Studies would be needed to determine the achievable higher rating upon the upgrade of Path 42. The Path 42 rating would be dependent on downstream impacts on the SCE system (if the increased schedules are to the CAISO grid), in addition to the technical performance of the re-conducted path. The impacts on the SCE's system west of their Devers Substation could be significant when considering the amount of existing generation and transmission interconnection requests in the queue for the Devers Substation area.

If the generation-transmission development follows the three phases outlined in this Report, Path 42 upgrade would not be required until 2020. However, if congestion occurs on Path 42 due to inadvertent flow resulting from delivery schedules to SDG&E's system, than the upgrade of Path 42 would become an economically driven project to reduce congestion costs.

2.3 Feasibility and Synergies with Regional Projects

Power flow, stability and post-transient analysis studies performed by the IVSG show the proposed plan to be capable of delivering 2,200 MW of new Imperial Valley generation to major regional buses without negative effect on reliability or grid operation across the region. All regional transmission owners having facilities that could be affected by the proposed plan participated in these studies; the studies themselves are described in Chapter 3. Production simulations performed by the CAISO indicate that implementation of the plan could potentially reduce wholesale power costs by several hundred million dollars/year.

The recommended plan takes advantage of two major projects proposed for the region: IID system upgrades; and a new 500 kV line from the Imperial Valley (IV) substation to San Diego County, with 230kV connections to SDG&E's load center. SDG&E's project to accomplish this is called the Sunrise Powerlink. SDGE has proposed building and owning this line and is in the process of planning this project, which was studied as part of the IVSG effort. Alternatively, portions of that line or another 500 kV line in Imperial County could be built and owned by IID.

Prior to the formation of the IVSG, the Imperial Irrigation District identified a comprehensive set of upgrades of its existing system that would enable it to export significant amounts of new generation from renewable resources in the Imperial Valley. It has presented this upgrade plan in CEC workshops and other fora as its Green Path initiative. It has completed many of the electrical studies, and has identified the environmental and permitting work necessary for these upgrades. The IVSG plan utilizes several (but not all) of these upgrades of the IID system.

The IID upgrades minimize environmental impact and appear cost effective because they upgrade existing facilities and require little new Right of Way (ROW). In many cases, higher capacity conductors can be mounted on existing towers, with little or no widening of ROW required. For purposes of the IVSG development plan, IID's planned Bannister substation is treated as an existing facility, because IID has committed contractually to build it under the terms of its agreement to purchase the output of CalEnergy's 215 MW Salton Sea Unit 6 geothermal plant, which expected on-line in 2008. The IVSG plan does require IID to add new facilities as well, including a collector substation at the Salton Sea geothermal field, to which most of the projected new geothermal power capacity would connect; and a new 230 kV line from the Bannister substation to a new 500/230 kV San Felipe substation, to connect to the proposed 500 kV Sunrise Powerlink to central San Diego.

The IVSG plan also takes advantage of a new 500 kV line from the Imperial Valley substation to San Diego County, which has been independently studied by SDG&E and a large transmission planning stakeholder review group. Ownership and operation of the portion of this line in Imperial County has not yet been determined. SDG&E requires this connection to ensure the reliable operation of its system after 2010. This line will also help the company to meet its RPS requirements for the purchase of renewable energy, and will provide access to lower cost power sources. The IVSG did not assume that the 500 kV line would be a component of its recommended plan. Instead, that line was one of a number of alternatives evaluated. The IVSG concluded after study that a 500 kV connection to the CAISO would be most effective. Connections at 230 kV were shown not to be as effective electrically, given the goal of exporting 2, 200 MW of power, and alternative paths for multiple 230 kV connections are limited in the region. The extensive studies of the Southern California region performed by SDG&E for its 500 kV Comparison Study provided both data and insight into regional needs and constraints. The IVSG was able to leverage this work in its own transmission planning studies.

The IVSG development plan anticipates scheduling most new Imperial Valley generation (except purchases by LADWP or Arizona LSEs) to SDG&E, to the extent possible. This avoids adding flows across Path 42 to the Devers substation. The very large volume of new flows expected at Devers are likely to require expensive network upgrades which, given the complexity of problem, may take several years to resolve. An export plan that relied on making Imperial Valley generation deliverable through Devers accordingly would risk delaying Imperial Valley development until a regional plan for resolving west of Devers issues is identified and approved.

When the amount of new generation connected in the Imperial Valley becomes substantial, this will create some unintended flow across Path 42, even with all the generation scheduled to SDG&E. IVSG studies found that in Phase 2, with 1,290 MW of renewable output scheduled to San Diego, unscheduled flow across Path 42 was 60 MW. In Phase 3, with 2,200 MW of new generation added, unscheduled flow across Path 42 was 210 MW. This flow requires the upgrades of Path 42 described above.

2.4 Production Cost, Congestion and Losses

The CAISO performed production cost simulations to estimate the economic and physical performance of the final three configurations of the IVSG generation/transmission development plan. These studies are described in detail in section 3.5 of this report. They indicate that adding 2,200 MW of new geothermal generation and the associated transmission in each of the various alternatives reduces WECC annual production cost, and congestion, by significant amounts. Each of the project alternatives reduced the hours of transmission congestion across the WECC by, on average, 4,400 hours/year (3%), as the new transmission capacity supported greater power flows. Losses increased, because generation in the Imperial Valley displaced more expensive generation closer to load. Adding the renewable generation reduced the total variable cost of generation WECC-wide by more than $500 million/year.

These simulations, however, were designed to compare transmission alternatives, not to justify investment decisions. Renewable generators have low marginal costs. Adding them to the generation mix will displace higher cost resources, thus reducing system-wide production cost. The simulations performed to date, however, were not designed to produce a reliable forecast of the potential savings. A full economic evaluation would have to model, among other things, a current forecast of gas prices, regional differences in gas prices, a range of hydro conditions, and the capital cost of the new generation and new transmission. The IVSG did not have the time to complete this work.

The IVSG determined that this report did not need to include a full economic evaluation of its recommended development plan, for several reasons: 1) full economic evaluation, which would entail significant additional work, is not expected of a conceptual plan. 2) with a connection to LADWP now being considered, the structure and timing of the phasing could change, making economic analysis premature. 3) SDG&E is working on an economic analysis of the 500 kV project, a major component of the IVSG plan, using the TEAM methodology; this includes the addition of 2,200 MW of geothermal generation in 2015. The results of that analysis, expected to be competed in October 2005, may help indicate the costs and benefits of the IVSG development plan.

2.5 Anticipated Development Schedule

(To be provided)

2.6 Triggers for Approval and Construction of Each Phase

(To be provided)

3.0 IVSG Transmission Studies

The conceptual development plan recommended by the IVSG is based on ten months of detailed transmission studies. These studies provide the basis for the development plan. This chapter describes the alternatives selected for evaluation, and the process used to study them.

3.1 Selection of Initial Export Path Study Alternatives

The IVSG was charged with identifying transmission solutions capable of exporting the 2,200 MW of new geothermal power from the Imperial Valley identified in the CEC Renewable Resources Development Report. IID, SDG&E, CalEnergy and CEERT first developed an initial list of export paths for study, consistent with this requirement: all alternatives had to be capable of delivering the full 2,200 MW. Other initial considerations were planned upgrades to the southwest regional grid being pursued through STEP; IID's plans to upgrade its own transmission system in order to support larger exports of renewable power from its control area; CalEnergy's development schedule for new geothermal generating units at the Salton Sea; and SDG&E's reliability-driven need for new EHV transmission by 2010 and its on-going Transmission Comparison Study.

Both 230 kV and 500 kV solutions were considered as study alternatives; upgrades at lower voltages were judged impractical for such a large-scale development. Upgrade of Path 45 through Mexico was considered; this would potentially enable flows from the Imperial Valley to Miguel, via Mexicali and Tijuana. This was abandoned because it would worsen the already-intractable transmission bottlenecks at the Imperial Valley and Miguel substations; would require ~80 miles of new transmission construction/new ROW through mountainous terrain in Baja Norte; and US-Mexico treaty negotiations and export licensing for flows from Mexico into California.

At its first meeting in November 2004, the IVSG discussed and unanimously adopted seven transmission alternatives for study, based on a list of routings suggested by IID, SDG&E and CalEnergy. Upgrades of the IID system were common to all the alternatives. The fact that the IID system extends around much of Imperial County makes it possible for renewable resources, including wind and solar, to connect in many locations, at workable voltages. The upgraded IID network would also directly access all KGRAs in the county. The key components of each alternative were:

1. **Alternative 1**: Imperial Valley (IV) substation to a new San Diego Central substation, at 230 kV; a new 230 kV connection from the IID Bannister substation to the proposed 230 kV, IV-SD Central line; and upgrades to the IID system (Midway–Parker; Midway-Highline; El Centro-Highline; El Centro-IV; Blythe-Know; Knob-Pilot Knob).

2. **Alternative 2**: same as Alt 1, but with Imperial Valley substation to a new San Diego Central substation, at 500 kV.

3. **Alternative 3a**: same as Alt 2, but with a 500 kV connection from IV to a new San Diego North substation (instead of a San Diego Central substation location).

4. **Alternative 3b**: same as Alt 3a, but with a connection to the SCE system from a new San Diego North substation across the Lake Elsinore Advanced Pumped Storage Project (LEAPS) route.

5. **Alternative 4a**: North Gila to Imperial Valley (IV) substation to a new San Diego Central substation, at 500 kV; plus all IID system upgrades.

6. **Alternative 4b**: same as Alt 4a, but with the proposed IID/APS Palo Verde-Yuma project added.

7. **Alternative 5**: same as Alt 2 (500 kV line, IV-SD Central), but with an additional 500 kV connection from the Imperial Valley substation north to the Palo-Verde-Devers #1 line, at a new Indian Hills substation; and a 230 kV connection from the IID Coachella Valley substation to the new Indian Hills substation.

3.2 Power Flow Studies

All IVSG power flow studies have been conducted using PSLF version 13.1. The IVSG Technical Work Group (TWG) first constructed base cases to represent the flows on the regional transmission system before adding any incremental Imperial Valley generation or any transmission upgrades, for Heavy Summer (maximum flows) and for Light Autumn (minimum flow conditions). It adopted a forecast of loads and resources for 2014, agreed on contingencies to consider, and developed a dispatch schedule to explore the export of Imperial Valley generation to different power customers. It then ran the 2014 Heavy Summer and Light Autumn cases with increments of new Imperial Valley generation added against the base cases, to evaluate the impacts and the upgrades needed.

Standard power flow planning criteria were employed.[7] Loading criteria were based on the normal or continuous rating (**Rating 2**) as identified in the cases.

[7] These criteria include:

- Pre-disturbance bus voltage must be between 0.95 per unit and 1.05 per unit.
- Allowable voltage deviation of five (5) percent for N-1 Contingencies (deviation from pre-disturbance voltage).
- Allowable voltage deviation of ten (10) percent for N-2 contingencies (deviation from pre disturbance voltage).
- Post transient bus voltage must be at least 0.90 per unit.
- Pre and post disturbance loading to remain within the emergency ratings of all equipment and line conductors. The emergency ratings are determined by the owner/operator of each equipment item.

3.2.1 Development of Base Cases

The IVSG chose 2014 as its study year, for two reasons: it could represent a plausible midpoint in the contemplated 2,200 MW generation-transmission development; and there was a WECC-approved Heavy Summer case for that planning year. There was, however, no WECC-approved Light Autumn base case for 2014. Instead, the TWG began with the WECC-approved 2009 Light Autumn case, and modified it to represent 2014 loads and resources.

The CAISO supplied an initial dataset of 2014 loads, resources and flows, for both Heavy Summer and Light Autumn periods. Each TWG Transmission Owner modified/updated this pre-project model in turn, to ensure that the loads, resources and flows on its system were accurately represented. This was essential, as the ISO does not have data on the IID, WAPA or CFE systems.

All Imperial Valley geothermal plants operating today were iterated as existing generation in the base cases. These include 80 MW at the Heber KGRA; 90 MW operated by Ormesa, also at Heber; 60 MW recently acquired by Ormat from Covanta; and 310 MW at the Salton Sea KGRA operated by CalEnergy. The base cases also include Salton Sea Unit 6, a 215 MW geothermal plant whose output IID has contracted to buy from CalEnergy. The base cases include the STEP Short-Term Upgrades (i.e., Path 49 is modeled with a 8,055 MW path rating), and a new Vincent-Mira Loma 500 kV line added in the LA Basin. The Devers-Palo Verde 2 line is included, but is modeled as off-line in the base cases.

3.2.2 Dispatch Scenarios

The study used CA ISO Generation Retirement assumptions, to identify units on the ISO grid likely not to be running in 2014. Consistent with ISO planning criteria, new geothermal/renewable generation, which has very low marginal cost, was assumed to displace higher cost generation around the region. Generating units assumed to be displaced are listed in the "Offset" column in Table 1.0 below.

The TWG developed different dispatch scenarios for each of the Heavy Summer and Light Autumn cases. These were designed to stress the regional transmission system under maximum and minimum flow conditions, in order to evaluate worst-case possibilities. The dispatch scenarios were also selected to represent likely or possible sales of power from Imperial Valley resources. The dispatch scenarios are listed in Table 3.1

3.2.3 Contingencies

Transmission Owners ("TO") each provided a transmission element outage list covering key facilities on their systems. These were compiled to form a master contingency list. This contingency list included N-1 (one single transmission component out of service) and N-2 contingencies (two transmission components out

Table 3.1 Dispatch Scenarios

AREA	D1 (summer only)		D2 (summer only)		D3 (autumn only)		D4 (autumn only)	
	Dispatch	Offset	Dispatch	Offset	Dispatch	Offset	Dispatch	Offset
IID	200	Elsteam 2,3 Repu2	200	Elsteam 2,3 Repu2	200	Elsteam 2,3 Repu2	200	Increased Load (200MW)
SDGE	1000	Encina 2,3,5 Southby 1,2,3 Eppst 1 Envirepl	200	Encina 2,3 Envirepl	200	Envirepl EPPCT2 Ramco_MR EPPST1	400	Eppct 1,2 Eppst 1 Envirepl Otaymst1 Ramco_mr
SCE	400	Alamt 5,6	300	Alamt 5,6	1000	Alamt 1,3 Redon 7, 8	600	Redon 7,8
LADWP	200	Valley 6,7,8	200	Valley 6,7,8	200	Valley 6 SCATT1G	200	Valley 6 Scatt 1G
PG&E	400	Morro 3,4	600	Morro 3,4 PTSB 5,6			800	DecCtG 1,2,3 DecStG1
WAPA			100	Griffth 1,2	100	Griffth 1		
ARIZONA			500	WPCC5ST1, WPCC5CT2 SANTN 5A, 6A IRVTGE4	500	WPCC5ST1, WPCC5CT2 SANTN 5A, 5B WPCC5CT1		
NPC			100	Clark 8,10				
total	2,200		2,200		2,200		2,200	

of service). The list also included transmission component forced outage to model events such as a circuit breaker failing to open. This master contingency list was run in each study to evaluate system reliability, feasibility and impact.

3.2.4 Heavy Summer Cases

The initial power flow modeling included 14 runs for the Heavy Summer cases (seven alternatives for each of the two dispatch scenarios shown on Table 3.1). Key findings of the Heavy Summer runs included:

- The IID 230kV and 500kV alternatives were found to be effective (no overloads within the IID controlled network) at delivering 2,200 MW of new resources out of the IID controlled network.
- The Salton Sea area collector system developed for this analysis is adequate to deliver approximately 2,000 MW of geothermal resources (the full potential of the Salton Sea KGRA) to the Midway and Bannister 230kV substations.

- Of the new alternatives, the 500 kV alternatives provided a higher level of deliverability to the regional system when compared to the 230 kV alternatives. However, depending on the magnitude of the new resources developed, initial deliveries can be made via 230kV system (e.g. new facilities constructed at 500 kV but operated initially at 230 kV). Also note that only approximately 30 miles of new ROW is required for all of the alternatives.

- Delivery constraints were noted at Miguel, Sycamore, Mirage, and Valley substations. Additional review of delivering the new resources beyond these facilities will be required by SDGE and SCE.

- The Imperial Valley – Miguel 500 kV line outage was found to be the most severe outage impacting the regional system with 2,200 MW of additional resources added within the IID transmission system.

- The Bannister – San Felipe, and Bannister – El Centro – Imperial Valley – San Felipe loop provides for added reliability of delivering higher amounts of geothermal resources to the SDG&E area loads (either at San Diego Central or San Diego North) under contingency conditions.

- The upgrades on Path 42 (both Coachella to Devers 230 kV lines) and an interconnection to the Palo Verde – Devers 500 kV line provides for added reliability of delivering higher amounts of geothermal resources to the SCE area loads under contingency conditions.

3.2.5 Selection of Final Study Alternatives

The results of the Heavy Summer cases showed that all of the initial alternatives were able to export 2,200 MW from the IID system. Some of the alternatives performed better than others, and some were found to be unnecessary for the export of 2,200 MW. This thermal analysis led the TWG to eliminate some of the alternatives from further study:

<u>Alternative 1</u> was dropped, because it did not meet objectives for reliability, access to renewable resources and low overall transmission costs as well as any of the 500 kV alternatives.

<u>Alternative 3a</u> was eliminated because it did perform as well as Alternative 3b, which provided a connection between the SDG&E and SCE systems and thus supported regional flows back to the east.

<u>Alternative 4a</u> was dropped because the connection to North Gila was found to be unnecessary for the export of new generation from the Imperial Valley.

Alternative 4b was eliminated because a second 500 kV connection was found to be unnecessary for the export of 2,200 MW, and because Alternatives 2 and 3 offered better electrical performance.

Alternative 5 was also dropped because a second 500 kV connection was found to be unnecessary.

Two of the original alternatives were selected for further evaluation based on the results of this screening analysis, and a variant on Alternative 2 was added:

1. Alternative 2: A new 500 kV line from Imperial Valley to San Diego Central, with 50 percent series compensation added to the San Felipe-to-San Diego Central portion of the line.
2. Alternative 2a: This variant on Alt 2 was added to evaluate the effect of adding a new 230 kV tie between IID and the CAISO at a new Indian Hills substation on the Devers-Palo Verde 1 line. It is the same as Alternative 2 except for this tie.
3. Alternative 3b[8]: A new 500 kV Imperial Valley to San Diego North to (SCE) Serrano-Valley transmission line, with 50 percent series compensation added to the San Felipe-to-San Diego North portion of the line.

Power flow studies were then performed on these three alternatives under Light Autumn load conditions. Stability studies and post-transient studies were later performed on these alternatives as well.

3.2.6 Light Autumn Cases

Additional power flow studies were performed for Alternatives 2, 2a and 3b under Light Autumn load conditions. The TWG developed two additional dispatch scenarios, as shown on Table 3.1, in order to stress the regional transmission system under Light Autumn load conditions. Six cases were studied (the three Alternatives, for each of two dispatch scenarios). Key findings of the Light Autumn runs included:

- The IID transmission system alternatives were found to be effective (no overloads within the IID controlled network) at delivering 2,200 MW of new resources out of the IID controlled network.

- The Salton Sea area collector system developed for this analysis is adequate to deliver approximately 2,000 MW of geothermal resources (from the Salton Sea KGRA) to the Midway and Bannister 230kV substations.

- Delivery constraints were noted at Miguel, Sycamore, Mirage, and Valley substations. Additional review of delivering the new resources beyond these facilities will be required by SDG&E and SCE.

[8] SDG&E determined in August 2005 that the best routing for a 500 kV connection to its system from the east would extend to a San Diego-Central substation, rather than to a San Diego-North location (as studied by the IVSG in its Alternative 3b).

- The Imperial Valley – Miguel 500 kV and Devers – Valley 500 kV line outages were found to be the most severe outage impacting the regional system with 2,200 MW of additional resources added within the IID transmission system.

- The upgrades on Path 42 (both Coachella to Devers 230 kV lines) and an interconnection to the Palo Verde – Devers 500 kV line provides for added reliability of delivering higher amounts of geothermal resources to the SCE area loads under contingency conditions.

Overall, these studies enabled the IVSG to develop a thorough understanding of the impact of adding 2,200 MW of new Imperial Valley generation on the flows at major regional buses. These flows are summarized in Table 3.2.

Table 3.2 Flows at Key Regional Buses

[to be provided by IID]

3.3 Stability Studies

Transient stability studies were conducted to test the alternatives under faulted conditions and system response to the faults with the additional resources connected to the system. The transient stability analysis was conducted on cases for both Heavy Summer and Light Autumn. For the Heavy Summer, stability analysis was conducted on Alternative 2 and Alternative 3b. For the Light Autumn, stability analysis was conducted on Alternatives 2 and 2a (with the interconnection to Indian Hills) and Alternative 3b.

The additional 2,200MW of generation was analyzed using the generator models employed for the Salton Sea #6 (geothermal plan) System Impact Study (200 MW each) 2,200. These models will have to be verified with updated models as part of the Salton Sea #6 interconnection requirements. But for the purposes of this feasibility analysis, the modeling for the additional resources was proven adequate and acceptable.

Table 3.5a represents the specific transient stability faults that were conducted for this analysis (HS for Heavy Summer and LA for Light Autumn).

Table 3.5a

	Power Flow Case and Associated Switch Decks				
Contingency	HS_ALT2_S1	HS_ALT3b_S1	LA_ALT2_S1	LA_ALT2a_S1	LA_ALT3b_S1
NERC/WECC Planning Standard - Category B (Loss of Single Element)					
IMPERIAL VALLEY-MIGUEL 500kV	ivml_noras	ivml_noras3	laivml_noras2	laivml_noras2a	laivml_noras3
HASSAYAMPA-NORTH GILA 500 kV	hang	hang3	lahang2	lahang2a	lahang3
DEVERS-MIDPOINT 500kV	NA	NA	lademp2	lademp2a	lademp3
SERVAL-VALLEY 500kV	NA	seva	NA	NA	laseva3
SERRANO-SERVAL 500kV	NA	sesv3	NA	NA	lasesv3
SERRANO-VALLEY 500kV	seva1	NA	laseva2	laseva2a	NA
DEVERS-VALLEY 500kV	deva	deva3	ladeva2	ladeva2a	ladeva3
SAN FELIPE-CENTRAL/NORTH SD 500 kV	nsfc	nsfn	lansfc2	lansfc2a	lansfn3b
IMPERIAL VALLEY-SAN FELIPE 500 kV	NA	NA	lansfi2	NA	lansfi3b
BANNISTER-SAN FELIPE 230kV	NA	NA	lansfb2	lansfb2a	lansfb3b
NERC/WECC Planning Standard - Category C (Loss of Two or More Elements)					
COACHELLA-DEVERS/MIRAGE 230kV N-2	NA	NA	lap42_noras2	lap42_noras2a	lap42_noras3b

Key findings of the Stability Analysis included:

- The IID transmission system alternatives were found to be effective and stable under the conditions and faults taken for this analysis.
- The most critical single contingencies were found to be the loss of Devers-Valley 500 kV line or the Imperial Valley-Miguel 500 kV line. These results were consistent the power flow (thermal) analysis.

- The lowest transient voltage (first swing voltage dip) was noted at the SCE Vista 230 kV bus for loss of the Devers-Valley 500 kV line.
- The addition of the Serrano/Valley to San Diego North 500 kV line was found to reduce the magnitude of the voltage dip at Vista 230 kV by providing an alternate source to Valley for loss of the Devers-Valley 500 kV line.

3.4 Post-Transient Analysis

The IVSG performed a Post-Transient analysis on the cases listed below, using the Reactive Power Margin Requirement criteria under the WECC Guidelines (NERC/WECC Planning Standards, I.D. WECC-G2) as a proxy for the WECC Standards I.D. WECC-S1, S2 and S3. In other words, this study was not performed using the WECC method of the increasing load or import by 105% or 102.5% (depending upon contingency) and then if the case solves, using that as proof of Post-Transient stability. Rather, this study was performed using the Reactive Power Margin Requirement (also know as V-Q Methodology developed by the Technical Studies Subcommittee of the WECC). The Reactive Power Margin Requirement provides a clearer, more accurate and definitive means to compare alternatives.

Appendix B.6 lists the study assumptions for the post-transient analysis, the contingencies run, buses monitored, reactive margin criteria applied, tables of reactive margin values, and Q-V curves for critical contingencies.

Cases Analyzed

The Post-Transient analysis was performed on seven cases: two Benchmark cases and five scenario cases using the GE PSLF Version 13.1 program. The benchmark cases represent Heavy Summer 2014 and Light Autumn 2014. There are two Heavy Summer alternative cases and three Light Autumn alternative cases. These seven cases were as follows:

1) Heavy Summer Benchmark (ivsg_hs_rev4)
2) HS, Imperial Valley – Central, Dispatch 1 (ivsg_hs_alt2d1_s1)
3) HS, Imperial Valley – Northern – Ser/Val, Dispatch 1 (ivsg_hs_alt3bd1_s1)
4) Light Autumn Benchmark (ivsg_la_rev5)
5) LA, Imperial Valley – Central, Dispatch 3 (ivsg_la_alt2d3_s1)
6) LA, Imperial Valley – Central & Coachella Valley – Indian Hills, Dispatch 3 (ivsg_la_alt2ad3_s1)
7) LA, Imperial Valley – Northern – Ser/Val, Dispatch 3 (ivsg_la_alt3bd3_s1)

Eighteen contingencies were run for this analysis, two of which did not apply to the two Benchmark cases. These included twelve single and six double contingencies.

In the analysis, 25 buses were monitored, including nine buses in SCE, seven buses in SDG&E, four in IID, four in CFE and one in MWD.

The Reactive Margin Criteria used in this study for SCE, SDG&E, CFE and IID was as follows: SCE - 300 Mvars (single element outage) and 150 Mvars (double element outage); SDG&E - 150 Mvars (single element outage) and 75 Mvars (double element outage); CFE - 100 Mvars (single element outage) and 50 Mvars (double element outage); IID - 100 Mvars (single element outage) and 50 Mvars (double element outage). It should be noted that the Reactive Margin Criteria used in this study are applicable only to this study and that they do not necessarily represent any utility's standard or policy.

This Post-Transient analysis considered the period of time after the power and voltage transient oscillations have damped out and before operator intervention can take place. This time frame is approximately one and half (1.5) to three (3) minutes subsequent to a disturbance.

Post-Transient Results

This analysis resulted in approximately 2,928 reactive margin values. Some of these reactive margin values are shown as Q-V curves which were produced for the most critical contingency for each case, with a representative assortment of buses included.

The most critical single contingencies were Imperial Valley – Miguel 500 kV and Devers – Valley 500 kV. Note the shift from the historic critical single contingency of Palo Verde – Devers to Devers – Valley 500 kV with the addition of Palo Verde – Devers #2. The most critical double contingency is the loss of Palo Verde – Devers 500 kV #1 and #2.[9]

The reactive margin values contained in the tables include shunt capacitor additions as indicated in the footnotes of the tables in the Appendix. With these additions, all buses met, or in most cases exceeded, the Reactive Margin Criteria. There is insufficient differentiation among margins, cases or seasons to strongly support one alternative over another.

In most cases, the reactive margin additions ranged from 150 Mvar to about 400 Mvar. Some of these additions will likely be part of other projects in the area, including the Sunrise Powerlink. The exception to needing no more than about 400 Mvar were some of the Light Autumn alternatives for the double contingency of Palo Verde – Devers 500 kV #1 and #2, which required as much as 1870 Mvar. However, this does not represent the real amount of reactive additions that would be required, as this Post-Transient study did not include the load dropping and/or other Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) which will be associated with this double contingency.

3.5 Production Cost Simulations

At the request of the IVSG, the CAISO performed production cost simulations to estimate the economic and physical performance of three final transmission configurations (Alternatives 2, 2a and 3b, as described in Section 3.2.5). The production cost simulation tool creates an economic generation dispatch that minimizes the total hourly production cost

[9] Note that the eastern termination of the Palo Verde – Devers #2 line is at Harquahala, not Palo Verde.

for the entire WECC transmission system, subject to generation, transmission and operational constraints. The output of the production simulation tool is processed to estimate the comparative production cost, loss and congestion savings of each of the alternatives. These results are useful in evaluating the viability of the transmission alternatives.

This study looked at comparative savings in WECC production cost, power losses and congestion hours due to the transmission projects. Other potential benefits such as market power mitigation, reduction in reliability-must-run generation cost, reduction in emissions and increased operational flexibility were not analyzed.

Study Description

The SSG-WI 2008 base case[10] was used as starting case. This base case includes generation and transmission infrastructure which are likely to be in place by 2008. The SSG-WI base case was updated to reflect forecasted 2010 load conditions in the study area (IID, SCE, SDG&E, CFE, LADWP and Arizona). New transmission and generation projects that are approved and planned to be online by 2010 in the Southwest area were modeled. These projects include:

- Harquahala-Devers 500 kV line
- New 500 kV Substation to be located at the Midpoint of Palo Verde- Devers and Harquahala-Devers 500 kV lines
- Blythe I and II Combined Cycle plant (1000 MW) connecting to Midpoint Substation
- Reconductoring of four West of Devers 230 kV lines
- Four new single cycle plants at CFE (340 MW)

The Benchmark base case used for the study modeled all the above projects. The project cases (Alternative 2, 2a and 3b) modeled the individual projects in addition to the 2,200 MW geothermal generation units. The geothermal units were considered to be base-load generators with must-run status. Startup/shut down cost, operation and maintenance costs, force outage rate and outage duration were modeled using typical values.

The following transmission facility assumptions were simulated as part of the study.

- All WECC transmission paths were modeled according to 2005 Path rating catalog
- Limits for all 500 kV transmission facilities were enforced.
- Lower voltage (230 kV and below) limits were not enforced.
- SDG&E Simultaneous import limit was not enforced.
- SCIT limit was modeled at 17900 MW
- EOR limit was modeled at 9255 MW
- WOR limit was modeled at 11318 MW
- Path 42 (IID-SCE) was limited to 600 MW in the benchmark case and 1600 MW in the project cases

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[10] SSG-WI, the Seams Steering Group-Western Interconnection, coordinates transmission expansion planning across the WECC. The base case was developed by the SSG-WI Planning Work Group.

- All AC transmission lines monitored were limited to 95% of their thermal capacity or applicable rating in order to accommodate reactive flows which are absent in this production simulation studies.
- Nomograms were used to reflect transmission system constraints.
- Transmission losses were modeled.
- Transmission line/Path limit violation penalty of $1000 per MWh was applied.

Production Cost optimization runs were performed using production cost tool to predict both the economic and physical performance of entire WECC transmission network with and without the projects on an hourly basis for 2010.

Sensitivity Studies

A sensitivity study was run to evaluate the addition of 2,200 MW of geothermal generation to the Benchmark case without new any new or upgraded transmission facilities (Benchmark-Sensitivity). This study was designed to quantify the proportion of the 2,200 MW of geothermal power that could be delivered without transmission upgrade, and the corresponding economic and physical performance of the system. This study assumed all the transmission facility limitations modeled in the Benchmark case. The limits for all 230 kV transmission lines in the IID area were also enforced.

In addition, a sensitivity on IVSG Project Alternative 2 was performed. This sensitivity case evaluates the economic and physical performance of extending the Imperial Valley-San Diego Central 500 kV line to the midpoint of the Valley-Serrano 500 kV line.

Production Cost Tool

The IVSG production cost simulation study was conducted using ABB's Gridview, which simulates the electricity market under realistic transmission system constraints, in hourly intervals. It incorporates a detailed supply model, demand model and a transmission system model. It uses an optimization algorithm that tries to dispatch generation resources such that the total production cost is minimized. The dispatch algorithm matches generation to hourly load and losses while taking into consideration transmission and operational constraints. Gridview program input data includes:

- Generation data, including capacity, fuel costs, heat rates, maintenance schedules, start-up/shut-down cost, up time, down time, forced outage rates and outage durations.
- Transmission data, such as network topology, thermal limits and operational constraints.
- Hourly demand data and distribution.
- Hourly hydro and wind dispatch.

Simulation outputs includes hourly dispatch for each generation unit, hourly production cost, hourly transmission line flows and Locational Marginal Prices at each WECC node.

Study Results

The simulation produced successful hourly production runs with sufficient generation resources to meet hourly demand and transmission losses subject to transmission and operational constraints for the benchmark and the project cases studied. Various transmission lines and interfaces were found congested for time periods ranging from one hour to several hours for all the cases studied. Appendix B.7.3 displays annual flow duration curves for major transmission lines and interfaces for all the cases studied.

WECC Annual Production Cost in the table below represents the total variable cost of generation for the entire WECC, before the new Imperial Valley generation is added (in the Benchmark cases), and after the 2,200 MW of renewable output is added in the other cases. Other key study results are the total hours of congestion on transmission interfaces and lines, and the total annual losses (MWh) on the transmission system. Table 3.5 provides a summary of the study results.

Study Cases	WECC Annual Production Cost (M$)	Total transmission Congested hours (hrs)	Total transmission losses (MWh)
Benchmark	15,731.35	146,206	34,687,733
Benchmark (Sensitivity)	15,471.24	172,887	33,863,293
Project Alternative 2	15,207.04	142,546	35,643,109
Project Alternative 2 (Sensitivity)	15,197.79	141,123	35,602,670
Project Alternative 2a	15,194.96	143,264	35,433,995
Project Alternative 3b	15,198.16	140,378	35,649,818

Table 3.5 Summary of Study Results

These study results indicate that Project Alternative 2a provides marginally greater savings in production cost and transmission losses. Looking at the congestion data, Project Alternative 3b provides a network that is least congested.

The sensitivity study results show that out of the 2,200 MW of geothermal units modeled in the Benchmark-Sensitivity case, only 800 MW could be delivered without new transmission facility additions. The hourly output profile of the geothermal units modeled in this sensitivity case is shown in Appendix B.7.2 The geothermal output might be substantially further reduced if transmission outage constraints were modeled. The results show that transmission congestion increased tremendously when new generation is added with transmission upgrades. Savings were nonetheless recorded in annual production cost and transmission losses with the geothermal units modeled. These savings might be eroded, however, if transmission outage constraints are included.

Project Alternative 2-Sensitivity study results showed a marginal saving in production cost, hours of congestion and transmission losses when compared to Project Alternative 2.

These production cost simulation study results, the results of the power flow and stability studies, and the cost of implementing the individual projects will all influence the choice of upgrade ultimately selected.

It is important to note that, as discussed in Chapter 2.4, this production cost simulation study was geared solely for comparing transmission alternatives. These study results do not provide an adequate basis for making investment decisions.

3.6 Further Study of Development Phases 1-3

The combination of thermal analysis, stability and post-transient analysis and production cost simulations established that each of the final alternatives were capable of exporting 2,200 MW of new Imperial Valley generation. The next task was to develop a plan for phasing this development. Three phases to accommodate the resource development were identified.

Phase 1: Transmission capability to export 645 MW of renewable resources by 2010.
Phase 2: Addition of 645 MW (1,290 MW of total development) by 2016.
Phase 3: Addition of 910 MW (2,200 MW of total development) by 2020.

The phasing analysis is based on a conceptual build and delivery of the renewable resources to markets. The first phase assumes that the transmission must be capable of exporting 645 MW of new renewable resource development from the Imperial Valley by 2010. IID identified two alternative routings for Phase 1:

- Alternative A, for power flows from the Salton Sea geothermal field to the north: upgrades to Path 42,[11] increasing the export capability of that path by 1,000 MW (from 600 MW to 1,600 MW of total transfer capability).

- Alternative B, for power flows from the Salton Sea geothermal field to the south and west: upgrades of the existing lines from Highline substation to El Centro to Imperial Valley substation, increasing the total transfer capability in that path to 1,600 MW.

The Technical Work Group conducted power flow studies to evaluate the performance of Alternatives A and B with 645 MW of generation added in Phase 1, 1,290 MW added with Phase 2, and 2,200 MW added with Phase 3. Phase 1 was studied with forecasted 2010 loads

[11] The IID Coachella-Ramon 230 kV line currently overloads with the loss of the Coachella-Mirage 230 kV line. As a result, action to correct this condition should be considered a pre-project upgrade (i.e., before Phase 1) since it is required to serve Coachella Valley load rather than for the export of renewable generation from the Imperial Valley.

for the IID, SCE and SDG&E planning areas; Phase 2 was studied with those loads increased by 11%, to approximate 2016 load levels.

Alternative A would schedule new Imperial Valley flows across Path 42 to the CAISO at the SCE Devers substation. The IVSG study shows that additional transfers through Devers to the west would be problematic. More than 5,000 MW of new generation, located in both Arizona and California is expected to flow to Devers; much of this is already in the SCE interconnection queue. SCE is developing a West of Devers upgrade plan. The TWG found that while the SCE system could accept 645 MW (Phase 1) at Devers, under both Light Autumn and Heavy Summer conditions, it could not accept 1,000 MW of additional flows from the Imperial Valley to Devers. Doing so would require further, large-scale upgrades of the SCE system in that region, such as a 500 kV tie from Devers to Valley, in addition to SCE's current upgrade plan. An export plan that relied on making Imperial Valley generation deliverable through Devers accordingly would risk delaying Imperial Valley development until a regional plan for resolving west of Devers issues is identified and approved.

Utilization of the routing in Alternative B, by contrast, would minimize Imperial Valley flows at Devers. TWG studies show that Alternative B accommodates the export of at least 645 MW in Phase 1, with cost-effective upgrades of existing IID lines in that routing. Alternative B requires the Imperial Valley – San Diego 500 kV line to be in service.

For Phase 2, TWG studies show that getting the 1,290 MW to flow to San Diego County rather than to Devers requires connecting the incremental Imperial Valley generation directly to the west side of the IID system, at its Bannister substation, and with a new 230 kV line from Bannister to a new San Felipe substation that could interconnect SDG&E's proposed 500 kV line into San Diego. Phase 2/Alternative B further requires that the existing El Centro – Bannister 161 kV be upgraded to 230 kV.

For Phase 3, further upgrade of the (Alternative B) Highline-El Centro-IV path, in addition to the Phase 2 Bannister-San Felipe tie and the 500 kV line into San Diego County, accommodates 2,200 MW of export. TWG studies show that with this amount of generation connected to the IID system, unintended flow across Path 42 could be in the range of 200 MW, thus requiring upgrades of that path.

After evaluating these study results of Phases 1-3, the TWG and the Steering Committee both concluded that the IVSG development plan should be based on Alternative B. This will minimize flows to Devers, thus avoiding the uncertainty, potential delays and high cost of that routing and instead, work to maximize utilization of the proposed 500 kV line into San Diego County.

3.7 Limitations of this Plan; Further Studies Necessary

The recommended development plan presented in this report is based on conceptual studies. It presents a general framework for expanding transmission capacity in the region but does not contain sufficient detail to evaluate the connection of specific generating projects.

Some of the conceptual studies themselves also had limitations. In the SCE planning area, some of the power flow studies performed for heavy load conditions did not include all projects in the SCE applications queue, whereas the power flow studies for light load conditions did include the majority of projects in the queue.

The IVSG development recommendation does not constitute a plan of service for the interconnection of any specific generating projects. IVSG studies did not address all the impacts of the proposed generation and transmission alternatives on the existing transmission system. System Impact Studies and Facilities Studies will be required when individual generating projects request interconnection to the IID system. These detailed load flow, short circuit, stability and post-transient studies must be done on a regional basis; they must address how to mitigate any potential system problems so that system reliability is maintained and the plan of service is demonstrated capable of meeting CAISO/WECC/NERC reliability standards. Interconnecting generators planning to sell power into CAISO grid must also submit a TO Tariff application, with all the details, to CAISO based on CAISO Tariff. In addition, WECC path rating studies will be required for the Sunrise Powerlink and for any other WECC path (such as Path 42) whose rating must be increased.

The IVSG did not undertake a full economic evaluation of the proposed generation-transmission development. Such an evaluation, using the TEAM or equivalent methodology, will be necessary to support approval of the significant financial investment required to implement this plan. SDG&E's economic evaluation of the Sunrise Powerlink includes substantial export flows of renewable generation from the Imperial Valley. If this SDG&E evaluation does not provide enough information about the potential benefits and costs of the IVSG development, then an additional economic evaluation should be scheduled, to coincide with the application to interconnect the first major increment of new Imperial Valley generation.

Most significantly, the IVSG did not consider a tie between the IID and LADWP systems, as this was not proposed by those parties until IVSG transmission planning had been completed. A 500/230 kV tie, as proposed at the Indian Hills substation, could alter the size, structure and timing of the development phases recommended in this plan. LADWP and IID have performed some studies of this link; additional power flow and other studies will be required to determine the effect of this connection on regional facilities, including the flow of new generation connected to the IID system.

4.0 Permitting and Approval Plan

The Permitting Work Group (PWG) met for seven months to develop a plan for coordinating and expediting the environmental studies and permit approvals required for all phases of the planned Imperial Valley renewables/transmission development. Participants included SDG&E, SCE, CalEnergy, non-jurisdictional utilities IID and LADWP, US Bureau of Land Management (BLM), CPUC, California Department of Parks and Recreation ("State Parks"), and other interested groups such as the Sierra Club and Border Power Working Group. The PWG identified the segmenting of environmental documents and the length of time for CPUC and CEC permit approval as key concerns to be addressed.

4.1 Environmental Review Documents: CEQA/NEPA

The PWG first explored the potential to develop one master environmental document to address both the regional benefits and the impacts of exporting renewable energy from the Imperial Valley. As the three development phases became better defined, it became apparent that the environmental documents would need to analyze the impacts of the project along the same time frames as proposed in those phases.

The IVSG anticipates Phase 1 in 2010, and Phase 3 in 2020. This span of over 12 years raised concerns about surveys becoming stale and findings that might not adequately review the environmental affects of the upgrades at the time they would be constructed. Meanwhile, much of the proposed transmission would provide other benefits to the individual utilities in addition to access to renewables. If each entity just analyzed their own separate component of a larger transmission plan, there would be concerns that the effects of the project were not analyzed as a whole but divided into manageable small areas to avoid reaching significant impacts. The PWG also grappled with who could/would be the lead agency for the document, given the involvement of both jurisdictional and non-jurisdictional utilities.

The PWG concluded that a programmatic approach provided the best vehicle to address all of the above concerns. The first step would be a broad, Programmatic EIR (P-EIR) that would take its project description from the development plan drafted by the IVSG. It would include at a high level:

- Impacts from the development of renewable resources in the Imperial Valley;
- Impacts from the upgrades of the IID system necessary to deliver geothermal /renewable energy out of the IID control area;
- Impacts of a 500 kV line from Imperial Valley to San Diego,
- Impacts of a 500 kV line from the proposed Indian Hills substation to Upland, possibly including a connection to the IID Coachella Valley substation.

In the Programmatic EIR, each of the above listed projects would have its own separate environmental documentation, and different lead agencies. By cooperating on the programmatic EIR, and sharing the study results for each utility's component of the project, the parties could save time and cost. This would also set the stage for the follow-on tiers of study work. The PWG agreed that the resource and permitting agencies should be brought into the planning effort on the programmatic document, in order to identify all areas of concern for detailed analysis in the follow-on documents. These agencies include the CEC, CPUC, California Department of Fish & Game, California Department of Parks and Recreation, U.S. Fish &Wildlife Service, U.S. Bureau of Land Management, and the Imperial County Planning Department. The involvement of representatives of these agencies will help identify all impacts early and hopefully expedite the follow-on documents.

4.1.1 Agreement to Work Cooperatively

To compile a joint programmatic document that could be used for tiering purposes, the PWG recommends that a Memorandum of Understanding be developed among IID, SDG&E, LADWP and CalEnergy, to share the costs for the programmatic EIR and the work of writing the descriptions of each entity's development plans. IID, LADWP, and SDG&E have already begun the independent environmental planning and study work for their portions of the project. This necessitates that the programmatic document be released and approved prior to the more detailed environmental analysis for the individual project components.

Currently, CalEnergy is the only generator intending to participate in the programmatic EIR effort. Other renewable generators interested in using the programmatic document to expedite their permitting study work are welcome to join the MOU. Doing so can help insure that their projects are analyzed in the context of the overall generation/transmission development.

Resource agencies and permitting authorities will also be invited to participate in the Programmatic EIR Working Group. They would not be parties to the MOU because they would not have cost responsibilities.

4.1.2 CEQA Lead Agency

The PWG recommends that IID act as the CEQA Lead on the programmatic document. IID's CEQA permitting action would be the approval by its board of directors of the proposed construction of the IID Green Path transmission plan, as part of the utility's system reliability upgrades.

The group discussed having the CPUC participate in the planning process on the programmatic document, either on the steering group or as a cooperating agency. This might enable the CPUC to utilize the Programmatic EIR as the Proponent's Environmental Assessment (PEA) required in the CPCN application process for jurisdictional utilities. If the CPUC would be willing to do this, it could reduce the normal processing time of a CPCN application by several months.

4.1.3 MOU/CEQA Cost

The PWG recommends that the costs of the Programmatic EIR be shared evenly among the MOU signatories. Details will be spelled out in the MOU. The costs to produce the document are estimated to be $300,000. Issues to be addressed in the MOU include:

- Composition and operational guidelines for the P-EIR Working Group
- Cost sharing
- Milestones
- Role Designations
- Responsible Parties

4.1.4 Timeline

The advantage of a Programmatic EIR with follow-on tiers is that the programmatic framework will be completed first. Because some permitting work has already begun, the PWG believes the P-EIR needs to be complete within six months of signing the MOU and hiring an environmental contractor. This would match up with the time frames given by IID, SDG&E, and LADWP for their documents:

- SDGE has begun study and environmental work on path alternatives for the Sunrise Powerlink, with the goal of construction start in January 2008 and completion in 2010.
- LADWP has begun environmental work on a 500 kV line, with a target for construction start in January 2008 and completion in January 2010.
- IID has completed planning work for its ten-year transmission plan and Green Path, and is prepared to request a major work authorization to start environmental and permitting work in fall 2005, with construction targeted to begin in 2007.
- CalEnergy has said it can build a geothermal plant every two years, contingent on signed PPAs for those plants. Meeting the 645 MW target for Phase 1 geothermal development by 2010 would require construction to begin in 2008 at the latest, with all three plants built simultaneously.

4.2 Rights of Way

The U.S. Bureau of Land Management (BLM)—both the El Centro and Palm Desert Field Offices—were instrumental in the PWG. The BLM identified the existing Utility Corridors that have been designated in the California Desert Conservation Plan areas in Riverside and Imperial Counties. The PWG investigated the feasibility of doing one NEPA document with the BLM to designate new utility corridors, in which utility Rights of Way could be granted for the project, but a consensus could not be reached. While the location of system upgrades to existing lines could be identified, all utilities had concerns about corridors being placed in their service territories which might allow other utilities to build within existing systems. In addition, those utilities still investigating routing alternatives were unable to identify potentially workable corridor locations precisely enough. Consequently, the PWG abandoned the idea of developing one NEPA document to amend the Desert Plan for the purpose of adding utility corridors. However, all the utilities will work to identify the location of necessary corridors so that such corridors can be presented in the Programmatic EIR. The actual NEPA documents to amend the Desert Plan will have to be developed in conjunction with the EIRs or EAs for the second tier of Imperial Valley generation/transmission development.

4.3 Permitting and Approval Processes

PWG members who have gone through state regulatory approval and permitting processes have many suggestions of ways to help speed them up. State and federal agency staffs have heavy workloads. One method of assisting them is to find ways to bring in consultants earlier in the process. Currently, it is only after the CPUC directs a utility to file a CPCN application that the utility can commit to pay for the staff consultant the CPUC assigns to the proposed project. In addition, a mechanism to bring the government agencies in from the very beginning could help insure that the environmental review addresses all agency concerns, thus producing documents able to be accepted without undue delay. Similarly, the public and all interested environmental/stakeholder groups should be invited to identify concerns to be addressed at the beginning of the environmental studies. This would help insure that all concerns are being addressed in a public and open manner. If the P-EIR sufficiently outlines the regional benefits of the entire renewable effort, identifies environmental areas of concern, and directs the necessary follow-up, the CPUC should be able to be utilize it for the applicant's PEA.

The federal agencies, while being able to be reimbursed for staff time, can only get involved when a permit or RoW is required. The PWG greatly appreciates the assistance of the El Centro and Palm Desert Field Offices of the BLM. They recommended that the utilities map out the necessary RoWs for all the phases and accomplish the Desert Plan amendments now, in anticipation of the need for the RoW, instead of doing separate NEPA documents and amendments for each phase. This is another way to cut down on regulatory agency staff work and time in order to speed up the process.

The Imperial County Planning Department is in the midst of revising the Geothermal Element in the County's General Plan. Their participation in the process enabled the PWG to understand the County's concerns. It highlighted the need for the utilities to comment on the Geothermal Element, in order to assist the County in updating the plan based on the current geothermal information being studied. Cooperative efforts such as this also help expedite the permitting process between the utilities and local agencies.

State Parks provided invaluable insight into the RoW through the park system and helped direct the planning efforts to look more effectively for routes through protected areas. The PWG recommends that State Parks be a participant in the planning effort for the P-EIR. Reluctance to further open park land for new utility corridors makes it a priority to utilize existing Park RoW for the necessary upgrades.

4.4 Next Steps

The PWG effort enabled all participants to better understand the regulatory approvals needed for the development of geothermal and other renewables in Imperial County. The major parties intend to negotiate an MOU for the joint production of a Programmatic EIR. They will also establish a meeting schedule to insure coordinated review of the environmental documents to be produced in the next year for the tiers of the project. By continuing to meet and share study information, the environmental contractors will be better able to adequately address the cumulative effects in each phase, and avoid overwhelming the government staffs that must review the documentation. Appendix C lists the range of permits that will be required from the different government departments for the transmission lines necessary to access the Imperial Valley Resources.

5. Tariff, Funding and Operational Control Issues

The IVSG development plan includes these major components: 1) network upgrades of the IID system; 2) the proposed SDG&E 500 kV line into San Diego County; 3) a potential 500/230 kV connection between IID and LADWP; and 4) in Phase 3, upgrades of the SCE Mirage –Devers tie and associated facilities on Path 42. IID and LADWP operate their own control areas, separate from the CAISO. The CPUC and FERC do not have jurisdiction over them. Both SDG&E and SCE are members of the CAISO, and fall under the jurisdiction of both the CPUC and FERC.

Renewable generators in the Imperial Valley will likely connect to the IID system, not the CAISO grid, even though most or all of their output is intended to be delivered to purchasers across the CAISO system. They will thus be required to comply with the IID OATT and its corresponding interconnection procedures.

The proposed SDG&E 500 kV line into San Diego County is by definition a CAISO network upgrade. Upgrades of the SCE system on Path 42 triggered by inadvertent flow would likely be considered an economically driven project to reduce congestion costs. Many components of the IID build-out will be considered network upgrades of that system; other IID (and LADWP) upgrades may be considered the cost responsibility of interconnecting generators, in whole or in part. Cost allocation is a critical issue, and these realities make the allocation of the costs of the required upgrades complex.

CAISO tariff provisions allow the cost of network upgrades of its system to be spread broadly, across all users of the ISO grid. Upgrades of the IID (and LADWP) systems cannot be spread as broadly. Generators interconnecting to the IID/LADWP systems may be required to bear some portion of the cost of the upgrades required to make their output deliverable to the CAISO grid. The amount of this generator cost responsibility will greatly affect the ability of geothermal and solar developers to sell their power. High wheeling charges could limit renewable development for export. Resolution of these issues remains a priority for IVSG parties. Some of the considerations involved are discussed in this chapter.

5.1. Transmission Cost Responsibility and Operational Control Issues

Cost responsibility for transmission upgrades to a non-FERC jurisdictional transmission system (*e.g.*, the IID transmission system) must be agreed by the affected parties. As a general matter, the party accepting ultimate cost responsibility for the transmission upgrades will require an ownership right in those upgrades.

SDG&E and SCE are Participating Transmission Owners (PTOs) of the grid operated by the CAISO. Any portion of a transmission upgrade, interconnection facilities, and associated facilities forming part of a PTO's transmission network will be transferred to the CAISO's operational control pursuant to the Transmission Control Agreement among the CAISO and PTOs.

PTOs could assume cost responsibility for upgrades in the IID control area under the following circumstances:

- PTOs may need to obtain a PTC or CPCN from the CPUC prior to the construction of such facilities;

- PTOs must be able to fully recover the costs of transmission upgrades and interconnection costs.

- Alternatively, the generation developer(s) could absorb the costs of these facilities and internalize those costs in the price at which it sells its output to a buyer(s). In such case, the generation developer(s) likely would require an ownership right in the transmission upgrades.

- IID could fund the upgrades to its system and recover its costs through an annual “wheeling charge” assessed to the party (*e.g.*, the generation developer(s) if the contract delivery point of the power is outside of the IID system; the buyer of the power if the contract delivery point is inside the IID control area) taking transmission service on the IID system.

5.2. Overview of Transmission Upgrades and Funding

IID and the IVSG Technical Work Group identified the transmission upgrades required to export geothermal resources located near the Salton Sea and other renewable resources in Imperial County. The majority of these upgrades were on the IID system; Phase 3 also requires upgrades of the SCE system. Additionally, SDG&E has proposed a new 500kV transmission line into San Diego County that will, among other benefits, facilitate delivery of this renewable generation to SDG&E and the CAISO grid.

The majority of upgrades associated with geothermal development near the Salton Sea are anticipated to be network upgrades. Some of the network upgrades may also be part of the grid assessment plan for the respective utilities. Therefore, some of these upgrades may need to be accelerated to accommodate geothermal development, on the schedule anticipated by the IVSG development plan.

Phase 1 development requires network upgrades of the IID system, and a new network addition to the SDG&E system. Phase 2 and Phase 3 system upgrades may entail more difficult funding issues.

Cost responsibilities for transmission upgrades are normally assigned to the utility that owns the affected facilities. The renewable resource area studied by the IVSG gives rise to unique cost responsibility issues. Some of the transmission upgrades on the IID system are required for the primary purpose of delivering geothermal energy to neighboring utilities. However, there are collateral benefits to IID’s system as the overall capability and reliability of the IID transmission system will be enhanced by the identified upgrades. Therefore, cost responsibility for the upgrades is potentially complicated.

5.3. Financing Options

Interested parties could pursue transmission ownership contracts, such as the SDG&E-IID California Project Participation Agreement. In this model, IID's ownership share may be in rough proportion to the benefits it would receive from the upgrades. IID would have the cost responsibility for its allocated portion of the project. PTOs who have transferred operational control of their transmission system to the CAISO, but who desire an allocated ownership portion of the new upgrade within IID's control area, would be responsible for a proportionate share of the remaining cost, reflecting their ownership share of the new upgrade.

If the utilities do not elect to own these new upgrades, a financing alternative would be for the generation developer(s) to work out their own arrangements with IID. As indicated previously, under this option, generators could internalize these transmission costs within their energy prices.

Another option is for the CAISO to direct its PTO's to fund upgrades of the IID system, which is outside of the CAISO control area, and allow for recovery through the CAISO's High Voltage Access Charge. The CAISO could direct such an action based on the need of its PTOs to meet state RPS goals. This action by the CAISO may not require transmission lines outside of the CAISO control to come under CAISO control.

5.4. Cost Recovery

IID operates its own control area. The IID control area interfaces with the CAISO at several points, including the Imperial Valley substation in the south and at the Devers Substation in the north; the proposed San Felipe substation would add a third delivery point. SDG&E and SCE have previously transferred operational control of their transmission facilities to the CAISO. PTOs recover the costs of a portion of pre-existing high voltage transmission facilities over a transition period, and all costs for new high voltage transmission through the CAISO's Transmission Access Charge (TAC). An appropriate portion of the costs for High Voltage Transmission facilities is billed through the TAC to all PTOs, which include SDG&E, SCE, PG&E and six municipal PTOs.

Rate recovery for a PTO's high voltage and low voltage transmission facilities that are *outside* the CAISO controlled-grid (*e.g.*, within the IID control area) would be subject to FERC jurisdiction. If accepted by FERC, the costs for high voltage transmission facilities would be socialized among all CAISO PTOs, as is currently done for SDG&E-owned and SCE-owned high voltage facilities within the CAISO controlled-grid**.**[12]

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[12] As noted earlier, the costs of certain high voltage transmission facilities are recovered in increasing percentages over a 10 year transition period after which time the entire cost of these facilities are recovered through the TAC.

6.0 Next Steps

6.1 Options for Expediting Permitting and Project Approvals

The IVSG Steering Committee identified the following options for expediting permitting and project approvals processes:

CPUC:

- Bifurcate CPCN applications into a Need Determination section, filed first; and an environmental study. This defers the cost of PEA development until the need for a project is established. It may also reduce the overall time required for CPCN application and approval.

- Request the CPUC to eliminate the current duplication of environmental study efforts, so that only one environmental report is required (rather than one produced by proponents and one by the CPUC).

- Alternatively, request the CPUC to hire its environmental contractor before the IOU files its CPCN application (or at the time the proponent files the Need Determination portion of the CPCN application).

- Allow the state Lead Agency to assign an environmental consultant to work with the utility’s (or Applicant’s) environmental consultant concurrently. This would enable the state Lead Agency’s environmental consultant to be involved during a project’s final route selection phase, and to develop the Draft EIS/EIR during the final four to six months of the PEA development. This option promotes earlier resource agency involvement. It would also reduce the redundancy between environmental impact assessments (PEA and EIS/EIR), and the overall timeframe associated with the development of the EIS/EIR.

CEC:

- Name the CEC, instead of the CPUC, as the state Lead Agency under CEQA.

- Use CEC public review of the IVSG report (e.g., in the IEPR proceeding) to be counted as one of the public meetings necessary in the CEC plant-siting approval process. This could save one month or more in this approval process.

- The CEC plant-siting process requires investigating alternative lines/connections. Request that the CEC accept the IVSG transmission studies as satisfying this requirement.

- Request the CEC to specify situations in which it could overrule CEC staff to provide flexibility in interpretation of CEQA requirements.

- Power Plant Permitting: transfer licensing authority and CEQA responsibilities from the CEC to a local agency. Permitting Salton Sea Unit 6 required 15 months from the time the CEC found the Application for Certification (AFC) to be "data adequate" in September 2002 to the formal approval of the AFC in December 2003.[13] By contrast, CalEnergy's 49 MW Salton Sea Unit 5 was permitted by Imperial County in less than four months. Imperial County has approved a resolution authorizing its Planning and Building Department to obtain siting authority from the CEC for plants up to 200 megawatts. The County believes that its 25 years of experience in permitting plants, in combination with appropriate land use ordinances mandated in its General Plan gives it the expertise to satisfy CEQA requirements and other concerns.[14] In 2001, Assemblyman Dave Kelley proposed legislation to modify Section 25540.5 of the California Public Resources Code to this end.

  A variation of this proposal would have the CEC incorporate local agencies' significant criteria into the CEC licensing process. This would make CEQA action in an area consistent between locally permitted generation facilities and CEC permitted projects. This could reduce concerns regarding noise, hazardous materials and biology, as local agencies are more familiar with local issues and industries. It would also thus eliminate the cookie cutter approach to significance and mitigation criteria used by the CEC. Local agencies can define overriding considerations (e.g., jobs, tax base, air quality) that could eliminate the need to incorporate some mitigation measures that do not yield measurable results relative to adjacent activities. One example of this would be the significant cost associated with fugitive dust mitigation measures imposed by the CEC in an area involved in major agricultural activities.

State:

- Amend CEQA to reduce the time and cost associated with power plant permitting, while strengthening standards for environmental impact and mitigation.

- Provide developers with access to existing incentive programs such as those in Government Code 51298, referred to as the California Investment Incentive Program.

Federal:

- Conduct joint federal/state agency meetings early in the process, particularly to focus on a joint EIR/EIS process.

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[13] It should be noted that Salton Sea Unit 6 was the first geothermal power plant to be permitted by the CEC in more than 15 years. It is reasonable to assume that the staff's "learning curve" associated with this permitting effort significantly lengthened the overall permitting process.

[14] The Imperial County General Plan contains a "Geothermal Element" that was developed to provide guidelines for permitting geothermal energy plants. Imperial County has used those guidelines to permit more than 14 plants. In conjunction with the Geothermal Element, Imperial County also prepared a Master Environmental Impact Report for the Salton Sea KGRA. That EIR is updated regularly.

- Pursuant to the Energy Act of 2005, coordinate federal agencies to enter into a Memorandum of Understanding (MOU) for the development of one environmental document for all necessary federal permits and approvals. The MOU should address schedule, criteria, and the coordination of state permits and approvals.

- Name the Department of Energy (DOE) as the federal Lead Agency under NEPA. The study and use of innovative technology may provide a means of establishing a funding mechanism with the DOE, which would then allow DOE to be identified as the federal Lead Agency under NEPA.

- Identify FERC as the federal Lead Agency under NEPA. The designation of national interest electric transmission corridors is identified within the Energy Act of 2005. The Act also recommends the FERC as the federal Lead Agency for projects proposed within these national interest corridors.

- Expedite the environmental review for projects in designated utility corridors once they are established. This involves the consideration of contingent corridors that would be evaluated at a programmatic level, and then elevated to 'designated' status upon a more detailed review at a project level.

6.2 Imperial Valley Implementation Group

The IVSG has provided a mechanism for key stakeholders to jointly create a planning framework for a complex, regional inter-utility, inter-control area development project. The agreement of IID, SDG&E, LADWP and CalEnergy to jointly produce a Programmatic EIR addressing the overall generation-transmission development is one valuable outcome of the IVSG effort. Collaborative electrical planning among utilities is another. The parties should extend this cooperation to the next stages of work required to implement the proposed development.

This work includes transmission studies of the proposed IID-LADWP tie, and its effect on exports of Imperial Valley generation to CAISO (and other) delivery points. This connection, and the size of DWP acquisitions of Imperial Valley renewables may require the size, timing and structure of the development phases recommended here to be reconfigured. Agreements among IID, LADWP and SDG&E as to the ownership and construction of proposed upgrades may also affect the structure and sequence of the overall development.

After the phases are better defined, on the basis of this new information, an economic evaluation of the costs and benefits of the overall development may be necessary. Cost responsibility and cost recovery issues also remain to be resolved. But the largest and most important implementation tasks are building the widespread public support necessary to overcome opposition to the construction of new facilities, and the winning of permit approvals.

Some of the work required for discrete transmission additions, e.g., WECC path rating studies, will be done by individual entities; commercial arrangements between the parties will be addressed through bilateral negotiations. But much of the next stage of work will be greatly facilitated by continued cooperation among stakeholders. Although parties have differing organizational interests, they may be able to achieve their objectives more effectively by attaching them to a larger development project.

To move this development forward, key stakeholders should transform the IVSG into a smaller Imperial Valley Implementation Group focused on permit approval and construction. This will provide a vehicle for collaborating on common tasks, for working out agreements on key issues, and for expediting all aspects of the joint generation-transmission development. An IV Implementation Group could establish goals and target dates for the overall development, and take responsibility for ensuring progress toward construction. It should report its progress quarterly, to stakeholders, the CPUC, CEC and Governor.